FORM EIA-861
ANNUAL ELECTRIC UTILITY REPORT - 1998

GENERAL INFORMATION

I. PURPOSE

Form EIA-861 collects information on the status of electric utilities and their generation, transmission, and distribution of electric energy in the United States, its territories, and Puerto Rico.

The data from this form are used to accurately maintain the EIA list of electric utilities, to draw samples for other electric power surveys, and to provide input for the following EIA publications: *Electric Sales and Revenue*, *Electric Power Monthly*, *Electric Power Annual Volume II*, *Annual Energy Outlook*, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*, and *Electric Trade in the United States*.

II. WHO MUST SUBMIT

This report is to be completed by each electric utility in the United States, its territories, and Puerto Rico. For the purpose of this report, an electric utility is a corporation, person, agency, authority, power marketer (registered with the Federal Energy Regulatory Commission (FERC)), or other legal entity or instrumentality that owns and/or operates facilities, including business premises, within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. Electric utilities must provide all requested information. Electric utilities that file the Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," with the Federal Government may respond to Schedule II (General Information, Peak Demand, Energy Sources, and Disposition), Schedule III (Electric Operating Revenue), Schedule IV (Electric Energy Information on Sales to Ultimate Consumers by State or U.S. Territory), and Schedule VI (Other Power Producer Information) of this form by attaching a copy of the appropriate schedules from the FERC Form 1. Electric Cooperatives that file the Rural Utilities Service (RUS) Forms 7, 7A, or 12, may respond to the Form EIA-861 by attaching a copy of the appropriate schedules from the RUS forms and submitting data on the Form EIA-861 not provided by the RUS forms. For respondents who also submit the Form EIA-826, “Monthly Electric Utility Sales and Revenue Report with State Distributions,” please coordinate that information with the Form EIA-861 to assure consistency between the surveys.

III. WHAT AND WHERE TO SUBMIT

Furnish information for the electric utility as it existed at the end of the calendar year (December 31).

Mail the completed, signed original and one copy of the Form EIA-861 in the enclosed postage-paid envelope or to the address below:

U.S. Department of Energy
Energy Information Administration, EI-53
Mail Stop: BG-076 (EIA-861)
1000 Independence Avenue, S.W.
Washington, D. C. 20077-5651

FAX telephone: (202) 426-1289

Retain a completed copy of this form for your files. For assistance in completing the form or questions, contact the **HELP CENTER** at voice phone (202) 426-1271 or FAX telephone (202) 426-1289. For additional information write to the above address or call:

Linda M. Bromley, voice telephone: (202) 426-1164,
E-Mail: linda.bromley@eia.doe.gov

IV. WHEN TO SUBMIT

Submit the completed form no later than April 30, following the close of the calendar year.

V. SANCTIONS AND CONFIDENTIALITY STATEMENTS

The timely submission of the Form EIA-861 by those required to report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275), as amended, and the Energy Policy Act of 1992 (Public Law 102-486). Failure to respond may result in a civil penalty of not more than $2,500 for each violation. The government may bring a civil action to prohibit reporting violations which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements. **Note: Data reported on the Form EIA-861 are not considered to be confidential.**

VI. QUALITY ASSURANCE

The Energy Information Administration (EIA) reviews and edits the data submitted on the Form EIA-861 for both completeness and accuracy. Manual and automated edits are performed to ensure that all required information is reported and that the data meet prescribed values or ranges. The following provides examples of the consistency checks that are used to validate information reported on the Form EIA-861.

Consistency checks are performed to ensure that revenue data are reported in thousand dollars and energy values are reported in megawatthours. One megawatthour equals 1,000 kilowatthours. To convert kilowatthours to megawatthours, divide by 1,000 and round to the nearest whole number.

Consistency checks are performed within and between different schedules. Rows and columns must sum to the totals as indicated below: 1) on Schedule II, item 11l, "Total source," should match item 11s, "Total disposition"; 2) on Schedule III, "Electric Operating Revenue," revenue data reported in items a-d, when summed, must equal item e; 3) on Schedule II, item 11m, "Sales to ultimate consumers," should match the total "Megawatthours," (sales to ultimate consumers) on Schedule IV, column g, when summed for all States; and 4) on Schedule III, item a, "Electric Operating Revenue from sales to ultimate consumers," should match the total "Revenue," (revenue from electric sales to ultimate consumers) on Schedule IV, column g, when summed for all States. Attention is given to the derived value for the average revenue per kilowatthour sold to ultimate consumers. On Schedule IV, to calculate the average revenue per kilowatthour for each consumer sector, divide the total annual revenue by the total annual megawatthours sold and multiply by 100 (if using kilowatthours, multiply by 100,000). Thus, Revenue ($1000) ÷ Megawatthours X 100 = cents per kilowatthour. Average revenue per kilowatthour are usually between 4.0 and 12.0 cents but may be higher or lower for a particular sector, ownership type, State, or region.

Additionally, attention is given to the average monthly consumption or usage for different consumer sectors. On Schedule IV, to calculate average monthly consumption for each consumer sector, divide the total annual megawatthours sold by the annual average number of consumers, divide by 12, and multiply by 1,000 to convert to kilowatthours. Thus, Megawatthours sold ÷ by the Number of Consumers ÷ 12 X 1000 = monthly consumption in kilowatthours. For 1997, the average monthly consumption at the national level for the residential sector was approximately 838 kilowatthours. The average monthly consumption at the national level for the commercial and industrial sectors was approximately 5,700 and 153,000 kilowatthours, respectively. These national averages are to be used as guidelines. The national averages for the commercial and industrial sector are not as accurate as that for the residential sector because the consumption for each individual commercial and industrial consumer tends to vary greatly due to different demand levels and the smaller consumer bases of these sectors.

Consistency checks are performed for capability. Capability is the maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress. The EIA derives a capability value for each electric utility by multiplying peak demand by the total number of hours in a year (8,760). An electric utility's total source or disposition of electricity on Schedule II should not exceed that capability value, assuming the value represents the maximum load the utility could carry if they operated at peak demand year round. In general, most utilities operate under 60 percent capability. Thus, Peak Demand (in kW) X 8,760 hours ÷ 1,000 (to convert to megawatthours) = Highest Potential Load. Also, reported Sources or Disposition ÷ Highest Potential Load = utility load factor. Data inconsistencies identified by the EIA will be verified with each electric utility through telephone contact.

GENERAL INSTRUCTIONS

1. Verify all preprinted information; if incorrect, draw a line through the incorrect entry and provide the correct information. Provide any missing information. Typed or legible handwritten entries are acceptable.

2. Report peak demand in kilowatts (kW) and energy values (e.g., generation and sales) in megawatthours (MWh), except where noted. One megawatthour equals 1,000 kilowatthours. To convert kilowatthours to megawatthours, divide by 1,000 and round to the nearest whole number. For example, sales of 5,245,790 kilowatthours should be reported as 5,246 megawatthours.

3. Report in whole numbers (i.e., no decimal points), except where explicitly instructed to report otherwise. All revenue data on Schedules III, IV, and V should be rounded and reported in thousand dollars. For example, revenue of $8,459,688.42 should be reported as $8,460.

4. Use a minus sign for reporting negative numbers.

5. Where exact data are unavailable, report estimated data.

6. See the glossary for definitions of terms in this report. The definitions of accounts are consistent as outlined in the Uniform System of Accounts for Public Utilities and Licensees (U.S. of A) (18 CFR Part 101).

GUIDELINES FOR PUBLICLY OWNED ELECTRIC UTILITIES

For various reasons (e.g., several offices completing the survey forms), respondents may report inconsistent data to related questions on different survey forms. To obtain consistency of data, the following are guidelines for publicly owned electric utilities that submit both the Form EIA-861, "Annual Electric Utility Report," and the Form EIA-412, "Annual Report of Public Electric Utilities." These guidelines provide a cross reference of data reported on the Form EIA-861, Schedule II, "Energy Sources and Disposition," items 11a-11s, and Schedule III, "Electric Operating Revenue," items a-d, that are similar to data reported on the Form EIA-412, Schedule II, "Electric Utility Income Statement for the Year," and Schedule IX, "Electric Energy Account." To ensure consistency of data, we recommend that you coordinate reporting on the Form EIA-861 with the contact person at your utility for the Form EIA-412. If you do not know the Form EIA-412 contact person at your utility, contact the HELP CENTER at the number listed on page 1 of these instructions. Please report all revenue values in thousands of dollars. Certain data items may not match exactly, thus a variance less than 5 percent is acceptable for utilities with a December 31 fiscal year ending. A variance of 20 percent is acceptable for utilities with fiscal year endings other than December 31.

I. For Form EIA-861, Schedule II, "Energy Sources and Disposition," items 11a-11s, refer to the Form EIA-412, page 9, Schedule IX. Please note that item 11n, "Requirements and nonrequirements sales for resale," is the aggregate of lines 19 and 20, "Requirements and Nonrequirements Sales for Resale," on the Form EIA-412.

II. For Form EIA-861, Schedule III, "Electric Operating Revenue," items a-c, refer to the Form EIA-412, page 3, Schedule II. Please note that operating revenue reported on line 1 of the Form EIA-412 includes revenue from electricity sales to ultimate consumers, requirements and nonrequirements sales for resale, and electric credits and other adjustments. Please separate these items and report them individually on Form EIA-861, Schedule III, items a-c, as follows:

1. Item a, Electric Operating Revenue from Electric sales to ultimate consumers;

2. Item b, Electric Operating Revenue from Requirements and nonrequirements sales for resale;

3. Item c, Electric Operating Revenue from Electric credits and other adjustments;

GUIDELINES FOR INVESTOR-OWNED ELECTRIC UTILITIES

For various reasons (e.g., several offices completing the survey forms), respondents may report inconsistent data to related questions on different survey forms. To obtain consistency of data the following are guidelines for investor-owned electric utilities that submit both the Form EIA-861, "Annual Electric Utility Report," and the FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others." These guidelines provide a cross reference of data reported on the Form EIA-861 that are similar to data reported on the FERC Form 1. Please use these guidelines when completing Schedules II, III, and IV of the Form EIA-861. To ensure consistency of data, we recommend that you coordinate reporting on the Form EIA-861 with the contact person at your utility for the FERC Form 1. If you do not know the FERC Form 1 contact person at your utility, contact the HELP CENTER at the number listed on page 1 of these instructions. Please report all revenue values in thousands of dollars and all energy values (e.g., generation and sales) in megawatthours (MWh) except where noted.

I. **Schedule II - General Information** (Energy Sources and Disposition)

For items 11a-11s, refer to the FERC Form 1, page 401, line numbers 9 through 28 for each corresponding data element. Please note: Page 401 of the FERC Form 1 aggregates the equivalent Form EIA-861 utility and nonutility purchased power information into one data element. Conversely, the requirements and nonrequirements sales for resale are aggregated on the Form EIA-861 and not on the FERC Form 1.

II. **Schedule III - Electric Operating Revenue**

For items a-d, refer to the FERC Form 1, page 300, column b, line numbers 10, 11, 13, and 26, respectively.

III. **Schedule IV - Electric Energy Information on Sales to Ultimate Consumers by State or U.S. Territory**

The sum of the State data provided on the Form EIA-861 should match the total electric utility data provided on the FERC Form 1. If the electric utility operates in only one State, a copy of pages 300-301 of the FERC Form 1 may be submitted in lieu of completing this schedule.

For columns b to e, item a, refer to the FERC Form 1, page 300, column b, line numbers 2, 4, 5, and 6, respectively.

For column f, item a, refer to the FERC Form 1, page 300, column b, line numbers 7, 8, and 9, totaled.

For columns b to e, item b, refer to the FERC Form 1, page 301, column d, line numbers 2, 4, 5, and 6, respectively.

For column f, item b, refer to the FERC Form 1, page 301, column d, line numbers 7, 8, and 9, totaled.

For columns b to e, item c, refer to the FERC Form 1, page 301, column f, line numbers 2, 4, 5, and 6, respectively.

For column f, item c, refer to the FERC Form 1, page 301, column f, line numbers 7, 8, and 9, totaled.

Please note that **unbilled sales and revenue** should be included on Schedule II, item 11m, and Schedule III, item a, respectively, so that the energy value on Schedule II, item 11m, matches the energy value on Schedule IV, column g (sales to ultimate consumers) when summed for all States and the revenue value on Schedule III, item a, matches the revenue value on Schedule IV, column g (electric operating revenue) when summed for all States.

SPECIFIC INSTRUCTIONS

SCHEDULE I - Identification and Certification

1. **Respondent Identification Code (EIA electric utility code):** These data will be entered by the EIA.

2. **Mailing name:** These data will be entered by the EIA.

3. **Exact Legal name:** Enter the legal name of the electric utility for which this form is being prepared.

4. **Brand/Commodity Name(s):** If marketing under a brand/commodity name, identify the name.

5. **Address of principal business office:** Enter the complete address, excluding the legal name, of the electric utility's principal business office (i.e., headquarters, main office, etc.).

6. **Mailing address for this form:** Enter the address to which this form should be mailed. Include an attention line, room number, building designation, etc. to facilitate the future handling and processing of the Form EIA-861.

7. **Contact person:** Enter the name, title, voice telephone number, e-mail address, and FAX telephone number of the individual to be contacted concerning the information provided on this form.

8. **Reviewing official:** Enter the name and title of the reviewing official. Also, enter the date the reviewing official signs the form.

SCHEDULE II - General Information

1. **Ownership:** Enter an "X" for ownership type that describes the electric utility.

2. **Relationship with the North American Electric Reliability Council (NERC) region:** Identify your relationship with the NERC by marking the region(s), or affiliate region with either: Member (M), Associate (A), or Nonmember (N).

The NERC regional councils are:

ASCC . . . . Alaska Systems Coordinating Council
ECAR . . . . East Central Area Reliability Coordination Agreement
ERCOT . . . . Electric Reliability Council of Texas
FRCC. . . . . Florida Reliability Coordinating Council
MAAC . . . . Mid-Atlantic Area Council
MAIN . . . . Mid-America Interconnected Network
MAPP . . . . Mid-Continent Area Power Pool
NPCC . . . . Northeast Power Coordinating Council
SERC . . . . Southeastern Electric Reliability Council
SPP . . . . Southwest Power Pool
WSCC . . . . Western Systems Coordinating Council

3. **Electric Control Area Operator:** Enter the name of the control area operator(s) under whose jurisdiction you operate.

4. **Operate generating plant:** Enter an "X" in Yes to indicate that the electric utility operated a generating plant during the reporting period. Otherwise, enter an "X" in No.

5. **For EIA Use.**

6. **Activities:** Enter an "X" to indicate which of the listed activities the electric utility was engaged in during the reporting year.

   a. **Generate from utility owned plants.**

   b. **Transmission using owned/leased electrical wires.**

   c. **Buying transmission services on other electrical systems.** Types of services include: borderline customers, transmission line rental, transmission capacity, transmission wheeling, system operational services.

   d. **Distribution using owned/leased electrical wires.** Distribution to your own end-use customers.

   e. **Buying distribution services on other electrical systems.** Types of support include customer billing, distribution system support charges for energy delivered, line maintenance, and/or equipment charges.

   f. **Wholesale power marketing.** With other electric utilities, purchases from nonutility power producers, and engaged in transactions to export and/or import electricity to, or from, Canada or Mexico. Electrical sales and purchases among FERC registered power marketers and similar participation in transactions with electric utilities by these registered entities are covered by this item.

   g. **Retail power marketing.** Provide electrical energy to retail customers in which the consumer has been given the legal right to select a power supplier that is other than their "traditional electric utility."

   h**. Provide ancillary service(s) support:** Provided ancillary services that include scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; and operating reserve (spinning reserve service and supplemental reserve service).

7. **Hourly peak demand:**

   a. Enter the maximum hourly summer (months June through September) load based on net energy for system during the reporting year. Net energy for the system is the sum of energy an electric utility needs to satisfy their service area and includes full and partial requirements (wholesale) consumers. The maximum hourly load is determined by the interval in which the 60-minute integrated demand is the greatest. If such data are unavailable, adjust available data to approximate a 60-minute demand interval and explain the adjustment under "Notes." If adjustments cannot be made, furnish data as available and explain under "Notes." Please note: Hourly peak demand is to be entered in kilowatts.

   b. Enter the maximum hourly winter (months January through March, and December) load based on net energy for system during the reporting year.

8. **Highest hourly firm requirements demand: (Power marketers only)** Enter the highest hourly firm requirements demand supplied for retail and for wholesale customers.

9. **Full requirements or partial requirements power supply contract termination date(s):** Enter the ending/termination year of the contract of any full or partial requirements contracts.

10. **Alternative Fueled Vehicles (AFV):** Enter an “X” in Yes to indicate that your company owns/operates, or plans to own and operate, AFV’s. Otherwise enter an “X” in No. If “Yes” provide the name, title, and telephone number of a contact person. Note: For the purpose of this question, an “alternative-fueled vehicle” is either designed and manufactured by an original equipment manufacturer or is a converted vehicle designed to operate in either dual-fuel, flexible-fuel, or dedicated modes on fuels other than gasoline or diesel. This does not include a conventional vehicle that is limited to operation on blended or reformulated gasoline fuels.

11. **Energy sources and disposition:** Enter the annual megawatthours (MWh) for each source and disposition listed.

    a. **Net generation:** Enter the net generation (gross generation minus plant use) from all electric utility owned plants. If a plant is jointly owned, enter only the reporting electric utility's share of generation. Include generation used to replace system losses arising from wheeling transactions.

    b. **Purchases from utilities:** Enter the total amount of energy purchased from electric utilities including: municipal departments and power agencies, cooperatives, investor-owned utilities, political subdivisions, State agencies and power pools, and marketing agencies of the United States Government and Canada; these agencies include the Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), Alaska Power Administration (APA), Tennessee Valley Authority (TVA), the United States Army Corps of Engineers, the United States Bureau of Reclamation, United States Bureau of Indian Affairs, and the International Boundary and Water Commission, Hydro-Quebec, etc. This entry includes requirements and nonrequirements purchased power.

    c. **Purchases from nonutilities:** Enter the total amount of energy purchased from nonutilities including: cogenerators, small power producers, and independent power producers. (See definition of nonutilities.)

    d**. Purchases from power marketers:** Enter the total amount of energy purchased from power marketers.

    e. **Exchange received:** Enter the amount of exchange energy received. (See Definitions.)

    f. **Exchange delivered:** Enter the amount of exchange energy delivered. (See Definitions.)

g. **Exchange net:** Enter the net amount of energy exchanged. Net exchange is the difference between the amount of exchange received and the amount of exchange delivered (item e - item f). (See Definitions.) This entry should not include wholesale energy purchased from or sold to electric utilities or nonutilities for other systems.

h. **Wheeling received:** Enter the total amount of energy entering your system from other systems for transmission through your system (wheeling) for delivery to other systems. (See Definitions.) Do not report as "Wheeling Received," energy purchased or exchanged for consumption within your system which was wheeled to you by others.

I. **Wheeling delivered:** Enter the total amount of energy leaving your system that was transmitted through your system for delivery to other systems. (See Definitions.) If "Wheeling Delivered" is not precisely known, calculate based on your system's known percentage of losses for wheeling transactions.

j. **Wheeling Net:** Enter the difference between the amount of energy entering your system for transmission through your system and the amount of energy leaving your system (item h - item I). Wheeling net represents the energy losses on your system associated with the wheeling of energy for other systems. (See Definitions.)

k. **Transmission by Others Losses:** Enter the amount of energy losses associated with the wheeling of electricity provided to your system by other utilities.

l. **Total sources:** Enter the sum of the energy sources (items a+b+c+d+g+j+k). This entry should be equal to Total disposition (item s).

m. **Sales to ultimate consumers:** Enter the amount of electricity sold to consumers purchasing electricity for their own use and not for resale. This entry should correspond to the revenue from sales to ultimate consumers reported on Schedule III, item a, and be the same total megawatthours reported on Schedule IV, column g, when summed for all reported States. This entry should include all unbilled megawatthours sold during the reporting period.

n. **Requirements and nonrequirements sales for resale:** Enter the amount of electricity sold for resale purposes. (See Definitions.) This entry should include sales for resale to full and partial requirements (firm) consumers and to nonrequirements (nonfirm) consumers. This entry should also correspond to the revenue from sales for resale reported in Schedule III, item b.

o. **Sales to power marketers for resale:** Enter the amount of electricity sold for resale purposes.

p. **Energy furnished without charge:** Enter the amount of electricity furnished by the electric utility without charge, such as to a municipality under a franchise agreement or for public street and highway lighting. This entry does not include "Energy used by utility's electric department," item q.

q. **Energy used by utility's electric department:** Enter the amount of electricity used by the electric utility in its electric and other departments without charge. This entry does not include "Energy furnished without charge," item p.

r. **Total energy losses:** Enter the total amount of electricity lost from transmission, distribution, and/or unaccounted for. This is the difference between "Total sources," item l, and the sum of items m-q.

s. **Total disposition:** Enter sum of the disposition of energy (items m+n+o+p+q+r). This entry should be equal to Total sources (item l).

SCHEDULE III - Electric Operating Revenue

All electric operating revenue data should be rounded and reported in thousand dollars (for example, revenue of $8,461,688.42 should be reported as $8,462).

a. **Electric operating revenue from sales to ultimate consumers:** Enter the amount of revenue from sales of electricity to those customers purchasing electricity for their own use and not for resale. This entry is a gross revenue and includes the revenue from State and local income taxes, energy or demand charges, consumer service charges, environmental surcharges, franchise fees, fuel adjustments and other miscellaneous charges applied to retail consumers during normal billing operations. This entry should **not** include deferred charges, credits, or other adjustments, such as fuel or revenue from purchased power, from previous reporting periods which are included in Schedule III, item c, "Electric credits and other adjustments." This entry should correspond to electricity sales reported in Schedule II, item 11m. This entry should also be the same total revenue reported on Schedule IV, column g, when summed for all reported States. This entry should include all unbilled revenue resulting from power sold during the reporting period.

b. **Electric operating revenue sales for resale:** Enter the amount of revenue from sales of electricity sold for resale purposes. (See Definitions.) This entry should include revenue from sales for resale to full and partial requirements consumers (firm) and to nonrequirements (nonfirm) consumers. This entry should also correspond to the sales for resale reported in Schedule II, item 11n. This entry should **not** include deferred charges, credits, or other adjustments, such as fuel or revenue from purchased power, from previous reporting periods which are included in Schedule III, item c, "Electric credits and other adjustments.

c. **Electric credits/other adjustments:** Enter the amount of **deferred** revenue which corresponds to Account 449.1 of the Uniform System of Accounts including revenue not applied to retail or resale consumers during the normal billing cycle. Funds included in this entry consist of refunds to consumers resulting from rate commission rulings delayed beyond the reporting year in which the funds were originally collected. Also, include revenue distributions to consumers from rate stabilization funds where the distribution occurred during the current reporting year but the funds were collected during previous reporting years. Do not include monthly fuel or purchased power adjustments reported on Schedule IV, "Electric Energy Information on Sales to Ultimate Consumers by State or U.S. Territory."

d. **Other electric operating revenue:** Enter the amount of revenue received from electric activities other than selling electricity. This may include revenue from selling or servicing electric appliances, revenue from the sale of water and water power for irrigation, domestic, industrial or hydroelectric operations, revenue from electric plants leased to others, revenue from the transmission of electricity for others (wheeling), revenue from the sale of steam, but not including sales made by a steam heating department or transfers of steam under joint facility operations, revenue from interdepartmental rents or electric property, revenue from late fees, penalties or reconnections, and revenue from interest and investments. Do not include this amount on Schedule IV, column f, line a, "Other Sales," where "Other" refers to the class of consumer.

e. **Total electric operating revenue:** Enter the total revenue received by the electric utility for the reporting year (items a+b+c+d).

SCHEDULE IV - Electric Energy Information on Sales to Ultimate Consumers by State or U.S. Territory

Enter the reporting year revenue (thousand dollars), megawatthours, and average number of consumers for sales of electricity to ultimate consumers by State or U.S. Territory and consumer class category. Determine the average number of consumers by the number of meters plus flat-rate accounts, except when separate meter readings are added for billing purposes. In this case, count one consumer for each meter group. "Average" means the average of the 12 close-of-month consumer counts. For public street and highway lighting, count all poles in a community as one.

a. **State (or Territory):** Enter the 2-letter U.S. Postal Service abbreviation (if not preprinted) for the State or U.S. Territory in which the electric sales occur (e.g., VA for Virginia, PR for Puerto Rico).

b. **Residential sales:** Enter the revenue, megawatthours, and average number of consumers for electric energy supplied for residential (household) purposes. For the residential class, do not duplicate the consumer accounts due to multiple metering for special services (e.g., water heating, etc.). (See Definitions.)

c. **Commercial sales:** Enter the revenue, megawatthours, and average number of consumers for electric energy supplied for commercial purposes. (See Definitions.)

d. **Industrial sales:** Enter the revenue, megawatthours, and average number of consumers for electric energy supplied for industrial purposes. (See Definitions.)

e. **Public street and highway lighting:** Enter the revenue, megawatthours, and average number of consumers for electric energy supplied to ultimate consumers for public street and highway lighting. (See Definitions.) If this service is provided without charge, the megawatthour sales should only be reported on Schedule II, item 11p., and not included in this entry.

f. **Other sales:** Enter the revenue, megawatthours, and average number of consumers for electric energy supplied to ultimate consumers **not** otherwise provided in residential, commercial, industrial, or public street and highway lighting (columns b, c, d, or e). This includes sales to railroads and railways, interdepartmental sales or sales to public authorities. (See Definitions.)

g. **Total sales:** Enter, for each State or U.S. Territory, the sum of the revenue, megawatthours, and average number of consumers entered for residential, commercial, industrial, public street and highway lighting and other sales (columns b+c+d+e+f). The aggregation of the revenue reported in this column for each State or U.S. Territory should equal the revenue reported on Schedule III, column a. The aggregation of megawatthours reported in this column for all States should equal the megawatthours reported on Schedule II, item 11m. Note: Power suppliers selling electricity in “retail wheeling” programs should report in “Notes:” on Schedule IV the revenue associated with reported consumers (including distribution charges, stranded costs, and other non-energy costs, even if estimated).

SCHEDULE V - Demand-Side Management Information

DSM programs are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Schedule V is divided into three parts: Part A, "Actual Effects"; Part B, "Projected Effects"; and Part C, "Actual and Projected Annual Costs."

Schedule V is to be completed by every utility with a utility-administered demand-side management (DSM) program. However, utilities with both sales to ultimate consumers and sales for resale which are less than 150,000 megawatthours are required to complete only Part A, "Incremental Effects," and the Total Utility Cost line of Part C, "Actual and Projected Annual Costs."

Reporting Guidelines

The DSM information provided should: (1) reflect only activities that are undertaken specifically in response to utility-administered programs, including activities implemented by third parties under contract to the utility, (2) account for the complete range of DSM programs, including Energy Efficiency and Load Management, and (3) represent the energy and load effects at the consumer meter (i.e., transmission and distribution or reserve requirement savings should be excluded). The DSM information should exclude, to the extent possible, energy and load effects that are not attributable to DSM program activities. Non-program related effects include changes in energy and load attributable to: (1) nonparticipants (e.g., consumers, known as freeriders, who would adopt program-recommended actions even without the program), (2) government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage, (3) natural operations of the marketplace (e.g., reductions in consumer energy usage due to higher prices), and (4) weather and business-cycle fluctuations.

Power supply cooperatives, municipal joint action agencies, and Federal Power Marketing Administrations are encouraged to coordinate the reporting of DSM information with their power purchasing utilities to avoid double counting the effects and costs of DSM programs. Utilities that have their DSM activities reported on the Schedule V of another utility should name that utility in the space provided on the schedule and not complete the Schedule V themselves.

To the extent possible, avoid using the Other Consumers category when reporting residential, commercial, or industrial consumers that are bound together by common rate structures or other similar treatment. It is preferred that the utility estimate each sector's effects and report them separately.

Please refer to the "Definitions" section for detailed descriptions of the key terms that begin with uppercase letters (e.g. Annual Effects, Load Management, Indirect Utility Cost).

Part A. Actual Effects

This part collects information on the energy and load effects of DSM programs implemented, and measures installed, for each program category by major consumer sector. It is divided into two subparts: (1) Incremental Effects and (2) Annual Effects. (See Definitions for a detailed description of each of the program categories, effects, and consumer sectors.)

1. Incremental Effects: The changes in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused in the current reporting year by **new participants** in your existing DSM programs and all participants in your **new DSM programs**. Reported Incremental Effects should be annualized to indicate the program effects that would have occurred had these participants been initiated into the program on January 1 of the current reporting year.

2. Annual Effects: The total changes in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused in the current reporting year by all participants in all of your DSM programs. This includes new and existing participants in existing programs (those implemented prior to the current reporting year that were in place during 1997), all participants in new programs (those implemented during 1997), and participants in programs terminated since 1992 (those effects continue even though the programs have been discontinued). DSM programs have a useful life, and the net effects of these programs will diminish over time. To the extent possible, the Annual Effects should consider the useful life of efficiency and load control measures by accounting for building demolition, equipment degradation, and program attrition. The effects of new participants in existing programs and all participants in new programs should be based on their start-up dates (i.e., if participants enter a program in July, only the effects from July to December are to be reported). If start-up dates are unknown and cannot be reasonably estimated, the effects can be annualized (i.e., assume the participants were initiated into the program on January 1). Please note that Annual Effects are not a summation of 12 monthly peaks, but are the total DSM program effects of all programs and all participants for the current reporting year.

For Part A, under the appropriate consumer sector (Residential, Commercial, Industrial, Other (note: agricultural and irrigation programs belong in "Industrial")), enter the aggregate Energy Effects (megawatthours) and Actual Peak Reduction (kilowatts) attributable to Energy Efficiency and Load Management programs. For Load Management also enter the Potential Peak reduction attributable to each consumer sector.

Part B. Actual Annual Cost

This part collects information on actual DSM program costs in the current reporting year (1998). Program costs consist of the cash expenditures, reported in thousands of dollars, incurred by the utility. Costs should reflect the total cash expenditures for the year, reported in nominal dollars, that flow out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occur. For example, the cash expenditures to purchase 1,000 load control devices for installation in consumers' homes could be incurred a year in advance of the actual load savings that result from operation of the devices.

Total Utility Cost: Enter your actual Direct Utility Cost and Indirect Utility Cost, incurred in the current reporting year. Direct Utility Costs are those costs that are directly attributable to a particular DSM program (e.g., Energy Efficiency or Load Management). Indirect Utility Costs are costs that may not be meaningfully included in any one of the program categories, but could be identified with an accounting cost category (i.e., Administrative, Marketing, Monitoring & Evaluation, Utility-Earned Incentives, Other). (See Definitions.)

Supplemental DSM Information

Please indicate, by checking yes or no, whether DSM program changes, tracking procedures, evaluations, or reporting methods have affected the data reported on this schedule (since 1992). If yes, please provide a brief description of the changes and how the data for Annual Effect, Incremental Effects, and costs have been impacted. Attach more pages if necessary.

SCHEDULE VI - Other Power Producer Information

For the purpose of this Schedule, other power producers are cogenerators, small power producers, and other nonutility generators, including independent power producers and commercial and industrial establishments with a total facility nameplate capacity of at least 1MW. Federal and State power marketing agencies such as Bonneville Power Administration, New York Power Authority and the Municipal Electric Authority of Georgia are considered to be electric utilities. Report all other power producers that operate or plan to operate in the reporting electric utility's service area (*regardless* of qualifying facility status, whether or not they are interconnected, or have the ability to supply electricity to the reporting electric utility).

1. Provide a list with the name, address (including zip code), telephone number (area code), and installed generator nameplate capacity in megawatts (MW) of all nonutility electric power producers that **OPERATE** in your service area. If the installed generator nameplate capacity of an entity is unknown or you are unsure, list the entity and report for the capacity "unknown." Electric utilities that respond to the FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and intend to supplement this schedule with a copy of the Schedule, "Purchased Power (Account 555)," pages 326-327, are asked to please review the schedule for accuracy and completeness of the names, including adding addresses, telephone numbers, and installed generator nameplate capacities of the nonutility entities reported. Please attach more pages if necessary.

2. Provide a list with the name, address (including zip code), telephone number (area code), and planned generator nameplate capacity in megawatts (MW) of all nonutility electric power producers that **PLAN TO OPERATE** in your service area. If the planned generator nameplate capacity of an entity is unknown, list the entity and report for the capacity "unknown." Please attach more pages if necessary.

SCHEDULE VII - Distribution System Information: Please verify the preprinted names of the counties, parishes, etc., by State, that your utility-owned distribution system electrical equipment are located in. The information preprinted may have been reported by your company last year or the result of independent research by the processing staff for the Form EIA-861.

SCHEDULE VIII - Footnote Data: This schedule provides additional space for comments. For clarification purposes, identify page, schedule, and item for each comment.

DEFINITIONS

1. Actual Peak Reduction - The actual reduction in annual peak load (measured in kilowatts) achieved by consumers that participate in a utility DSM program. It reflects the changes in the demand for electricity resulting from a utility DSM program that is in effect at the same time the utility experiences its annual peak load, as opposed to the installed peak load reduction capability (i.e., Potential Peak Reduction). It should account for the regular cycling of energy efficient units during the period of annual peak load.

2. Administrative Cost - Expenses incurred by the utility for staff involved in program planning, design, management, and administration. They include labor-related expenses, office supplies, data processing, and other such costs. They exclude the costs of marketing materials and advertising, purchases of equipment for specific programs, and rebates and other cash incentives.

3. Annual Effects - The total changes in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused by all participants in your DSM programs. This includes new and existing participants in existing programs (those implemented in prior years that are in place during the given year), all participants in new programs (those implemented during the given year), and participants in DSM programs that were terminated after 1992. DSM measures have a useful life and the net effects of these measures diminish over time. To the extent possible, the Annual Effects should consider the useful life of efficiency and load control measures by accounting for building demolition, equipment degradation, and program attrition. The effects of new participants in existing programs and all participants in new programs should be based on their start-up dates (i.e., if participants enter a program in July, only the effects from July to December should be reported). If start-up dates are unknown and cannot be reasonably estimated, the effects can be annualized (i.e., assume the participants were initiated into the program on January 1 of the given year). If you are operating a DSM program with dual Energy Efficiency and Load Building objective, separate the effects and report each in the appropriate program category. Please note that Annual Effects are **not** a summation of 12 monthly peaks or the aggregate of the Incremental Effects for the reporting year, but are the total effects of all DSM programs for all participants (new and existing) for the year.

4. Capability - The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

5. Cogenerator - A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy" and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). (See the code of Federal Regulations, Title 18, Part 292.)

6. Commercial - The consumers of the commercial sector that are generally defined as nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions (North American Industry Classification System (NAICS) codes 521-8149). The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility. Sales to consumers that the utility has no system for separating into residential, commercial and industrial classifications, should be classified based on the classification of the consumers that their rate schedule most closely resembles. If there is no rate distinction, report commercial consumers as those with demand less than 1,000 kilowatts.

7. Demand-Side Management - The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers to only energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

8. Direct Utility Cost - A utility cost that is identified with one of the DSM program categories (i.e., Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, Load Building).

9. Electric Control Area Operator - Control area operator is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied to match the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s); maintain scheduled interchange with other control areas; maintain the frequency of the electric power system(s) within reasonable limits; and provide sufficient generating capacity to maintain operating reserves. There are approximately 150 electric control area operators in the United States.

10. Energy Effects - The changes in aggregate electricity use (measured in megawatthours) for consumers that participate in a utility DSM program. Energy Effects should represent changes at the consumer meter (i.e., exclude transmission and distribution effects) and reflect only activities that are undertaken specifically in response to utility-administered programs, including those activities implemented by third parties under contract to the utility. To the extent possible, Energy Effects should exclude non-program related effects such as changes in energy usage attributable to nonparticipants, government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage, changes in consumer behavior that result in greater energy use after initiation in a DSM program, the natural operations of the marketplace, and weather and business-cycle adjustments.

11. Energy Efficiency - Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatthours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include energy saving appliances and lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

12. Exchange Energy - Exchange energy refers to specific electricity transactions between electric utilities, where electricity received is returned in kind at a later time or accumulated as energy balances until the end of the stated period, after which settlement may be by monetary payment.

13. Full Requirements Consumer - A wholesale consumer without other generating resources whose electric energy seller is the sole source of long-term **firm** power for the consumer's service area. The terms and conditions of sale are equivalent to the seller's obligations to its own retail services, if any.

14. Generator Nameplate Capacity - The full-load continuous rating of a generator under specified conditions as designated by the manufacturer. Generator nameplate capacity is usually indicated on a nameplate attached physically to the equipment.

15. Heating System - Energy Efficiency program promotion aimed at improving the efficiency of the heating delivery system, including replacement, in the residential, commercial, or industrial sectors.

16. Incremental Effects - The annual changes in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused by **new participants** in your existing DSM programs and all participants in your **new DSM programs** during a given year. Reported Incremental Effects should be annualized to indicate the program effects that would have occurred had these participants been initiated into the program on January 1 of the given year. Incremental effects are not simply the Annual Effects of a given year minus the Annual Effects of the prior year, since these net effects would fail to account for program attrition, equipment degradation, building demolition, and participant dropouts. Please note that Incremental Effects are not a monthly desegregate of the Annual Effects, but are the total year's effects of only the new participants and programs for that year.

17. Independent Power Producer (IPP) - IPP's are wholesale electricity producers, other than qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA), that are unaffiliated with franchised utilities in the area in which the IPPs are selling power and that lack significant marketing power. Unlike traditional utilities, IPPs do not possess transmission facilities that are essential to their customers and do not sell power in any retail service territory where they have a franchise. An IPP is an entity that is not a qualifying facility.

18. Indirect Utility Cost - A utility cost that may not be meaningfully identified with any particular DSM program category. Indirect costs could be attributable to one of several accounting cost categories (i.e., Administrative, Marketing, Monitoring & Evaluation, Utility-Earned Incentives, Other). Accounting costs that are known DSM program costs should not be reported under Indirect Utility Cost; those costs should be reported as Direct Utility Costs under the appropriate DSM program category.

19. Industrial - Consumers of the industrial sector generally defined as manufacturing, construction, mining, agriculture, fishing, and forestry establishments (North American Industry Classification System (NAICS) codes 11 - 3399). A utility may classify industrial service using NAICS codes or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

20. Interconnection - Two or more electric systems having a common transmission line that permits a flow of energy between them. The physical connection of the electric power transmission facilities allows for the sale or exchange of energy.

21. Interdepartmental Service (Electric) - Interdepartmental service includes amounts charged by the electric department at tariff or other specified rates for electricity supplied by it to other utility departments.

22. Kilowatt (kW) -One thousand watts.

23. Kilowatthour (kWh) - One thousand watthours.

24. Load Management - Refers to all DSM programs designed to reduce consumer load at the time of system peak. The Load Management category is the sum of all peak reduction programs which previously were reported on the Schedule V of the Form EIA-861 as Direct Load Control, Interruptible Load, Other Load Management, or Other DSM Programs.

25. Maximum Hourly Load - This is determined by the interval in which the 60-minute integrated demand is the greatest.

26. Megawatt (MW) - One million watts.

27. Megawatthour (MWh) - One million watthours.

28. Net Energy for System - The sum of energy an electric utility needs to satisfy their service areas and includes full and partial requirements wholesale consumers.

29. Net Generation - Gross generation minus plant use from all electric utility owned plants. The energy required for pumping at a pumped-storage plant is regarded as plant use and must be deducted from the gross generation.

30. Nonrequirements Consumer - A wholesale consumer (unlike a full or partial requirements consumer) that purchases economic or coordination power to supplement their own or another system's energy needs.

31. Nonutility Power Producer - A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

32. Other Consumers - A residual category to capture the consumers that are not covered by the residential, commercial, industrial, and public street and highway lighting consumer categories listed and defined herein. This category may include electrified rail, interdepartmental, or public authority sales. To the extent possible, avoid using the Other Consumers category when reporting commercial and industrial consumers that are bound together by common rate structures or other similar treatment. It is preferred that the utility estimate each sector's effects and report them separately. Note that consumers involved in agriculture are included in Industrial Consumers.

33. Other Power Producer - A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Other Power Producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchise service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

34. Partial Requirements Consumer - A wholesale consumer with generating resources insufficient to carry all its load and whose energy seller is a long-term firm power source supplemental to the consumer's own generation or energy received from others. The terms and conditions of sale are similar to those for a full requirements consumer.

35. Peak Demand - The maximum load during a specified period of time.

36. Potential Peak Reduction - The potential annual peak load reduction (measured in kilowatts) that can be deployed from Direct Load Control, Interruptible Load, Other Load Management, and Other DSM Program activities. (Please note that Energy Efficiency and Load Building are not included in Potential Peak Reduction.) It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load.

37. Power Marketers - Business entities that are engaged in buying and selling electricity, but do not own generating or transmission facilities. Power marketers, as opposed to Brokers, take ownership of the electricity and are involved in interstate trade. Power marketers file with the Federal Energy Regulatory Commission for status as a power marketer.

38. Public Street and Highway Lighting - Includes electricity supplied and services rendered for the purpose of lighting streets, highways, parks, and other public places, or for traffic or other signal system service for municipalities or other divisions or agencies of State or Federal governments.

39. Qualifying Facility (QF) - A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.)

40. Railroad and Railway Services - Railroad and railway services include electricity supplied and services rendered to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules.

41. Resale (Wholesale) Sales - Resale or wholesale sales are electricity sold (except under exchange agreements) to other electric utilities or to public authorities for resale distribution. (This includes sales to requirements and nonrequirements consumers.)

42. Residential - The consumers of the residential sector that are generally defined as household establishments that consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. For the residential class, do not duplicate consumer accounts due to multiple metering for special services (e.g., water heating). Apartment houses and other multi-unit dwellings are included.

43. Service to Public Authorities - Public authority service includes electricity supplied and services rendered to municipalities or divisions or agencies of State and Federal governments, under special contracts or agreements or service classifications applicable only to public authorities.

44. Small Power Producer (SPP) - Under the Public Utility Regulatory Policies Act (PURPA), a small power production facility (or small power producer) generates electricity using waste, renewables (water, wind, and solar) or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resources must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

45. Total Utility Cost - Refers to the sum of the total Direct and Indirect Utility Costs for the year. Utility costs should reflect the total cash expenditures for the year, reported in nominal dollars, that flowed out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occur.

46. Transmission by Others Losses - Energy losses associated with the wheeling of electricity provided to an electric utility system by other electric utilities.

47. Utility Demand-Side Management Costs - The costs incurred by the utility to achieve the capacity and energy savings from the Demand-Side Management Program. Costs incurred by consumers or third parties are to be excluded. The costs are to be reported in nominal dollars in the year in which they are incurred, regardless of when the savings occur. The utility costs are all the annual expenses (labor, administrative, equipment, incentives, marketing, monitoring and evaluation, and other) incurred by the utility for operation of the DSM Program, regardless of whether the costs are expensed or capitalized. Lump sum capital costs (typically accrued over several years prior to start up) are not to be reported. Program costs associated with strategic load growth activities are also to be excluded.

48. Wheeling - The use of the transmission facilities of one system to transmit power and energy by agreement of, and for, another system with a corresponding wheeling charge, (e.g., the transmission of electricity over an electric utility's system for compensation), which the electric utility received from one system and delivered to another system.